Indiana Utility Regulatory Commission

2005

Gas Report to the Regulatory Flexibility Committee of the Indiana General Assembly

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EXECUTIVE SUMMARY

During the 2004–2005 heating season there were sharp increases in residential heating bills, although they were still slightly below the level seen during the 2000–2001 winter. Winter temperatures in most regions were either average or higher than average, but prices were sustained and elevated due to several cold snaps in the East and Northeast.

In the late summer and fall of 2004, heavy hurricane activity in the Atlantic Ocean was a contributing factor to high prices. The threat of a reduction in oil supply because of the continued U.S. involvement in Iraq was also a factor in increased prices. Elevated natural gas prices continue to be due, in part, to basic economic factors of supply and demand.

In economic terms, gas supply is tight. New sources and new technologies will alleviate some of the price pressure; but it will take time and will come at a high dollar cost. Demand, while down in some sectors, is not following the old path of peaking only during the winter season. Producers and local distribution companies (LDCs) continue to face the recent trend of a significant summer demand peak. The increased use of natural gas as the primary fuel source for electric peaking plants, typically designed to run during the summer months, is a major contributor to these summer demand peaks.

In addition to issues surrounding the volatile gas market, there have been other issues in the spotlight during the past year. They include a Gas Forum and a customer rights and responsibilities rulemaking. The Gas Forum was held on July 29, 2005 and consisted of three panels: 1) unique issues facing small LDCs, 2) gas purchasing, portfolio management, and the role of the marketer, and 3) efficiency, conservation, and weatherization. The Indiana Utility Regulatory Commission (IURC or the Commission) anticipates holding a second part to this forum to allow the utilities to return to discuss gas prices as it gets closer to the heating season.

As a comprehensive way of addressing customer rights and responsibilities across all regulated industries, the Commission published a Notice of Intent to Adopt and issued a Notice of Proposed Rulemaking. After public hearing and receipt of feedback, the Commission decided there was inadequate time to complete the rulemaking under normal rulemaking timelines and withdrew the proposed rule. On June 1, 2005, the Commission restarted the process, but solely for gas utilities.

These and other issues are highlighted in the following Report. Topics to be discussed in more detail include: 1) natural gas industry overview, 2) Commission actions addressing price volatility and supply reliability, 3) other gas issues affecting Indiana, and 4) competitive issues in natural gas.

Natural Gas Industry Overview

Industry Structure

Local gas distribution companies are generally either investor-owned or not-for-profit. Despite their different forms of ownership and corporate structures, investor-owned and not-for-profit utilities share the goal of providing reliable gas service at reasonable cost. These utilities serve as resellers and transporters of gas to their retail customers.

Typically, gas utilities purchase gas supply and transportation rights rather than having any ownership in production or pipeline facilities (they are not vertically integrated[1]). LDCs buy their gas and transportation rights through contracts. Gas prices are set in the open market while the Federal Energy Regulatory Commission (FERC) regulates the transportation rates for interstate pipelines**.**

Investor-Owned Utilities

Investor-owned utilities (IOUs) are the largest sellers of natural gas to retail customers in the United States. In Indiana, there are three large IOUs providing gas service: Indiana Gas Company, Inc. (IGC), Northern Indiana Public Service Company (NIPSCO) and Southern Indiana Gas and Electric Company, Inc. (SIGECO), and 16 smaller IOUs. The three largest IOUs are owned by holding companies with NiSource as the parent of NIPSCO and Vectren owning Indiana Gas and SIGECO. Two of these companies, NIPSCO and SIGECO, are combination utilities that provide electric service as well as gas service.

Not-For-Profit Utilities

Not-for-profits are incorporated organizations in which no stockholder or trustee shares in profits or losses. In addition, they are exempt from corporate income taxes. On May 5, 2002, the Commission issued a Certificate of Territorial Authority (CTA) in its Order in Cause No. 42115 to Valley Rural Utility

[1] Vertical integration is a firm's involvement in all stages of the production of goods, from the procurement of raw materials to the sale of finished goods.

Company. Valley Rural is organized as a not-for-profit and is now providing service to a single residential development.

Municipals are organized as not-for-profit local government entities. They pay no federal taxes or dividends, although revenue can be turned over to the general city fund in lieu of taxes if the city elects to do so, and they raise capital through the issuance of tax-free bonds. There are 19 municipally owned gas utilities in Indiana, but only two are regulated by the Indiana Utility Regulatory Commission (IURC or Commission). The state's largest municipal gas utility, Citizens Gas and Coke Utility (Citizens)[2], which serves Marion County, and Aurora Municipal Utility are the only two regulated by the Commission. The remaining municipal utilities have "opted out" of the Commission's jurisdiction.[3]

Indiana Sales and Transportation of Gas

Gas utilities serve as both merchants providing bundled sales and transportation service to many of their customers and transporters moving gas through their systems for industrial and commercial customers that have purchased gas directly from producers or marketers. Interstate pipeline companies transport gas to the points of delivery (also known as City Gates) where it enters the LDC's system for distribution to its customers.

The following table presents sales information for Indiana's four largest LDCs: Citizens Gas, Indiana Gas, NIPSCO, and SIGECO. Sales figures are based on sales of gas made by LDCs to customers that purchase bundled service, which includes both the provision of gas and its transportation. These four companies collectively represent about 90 percent of the natural gas retail deliveries in the state. For more detailed information, see Appendix A.[4]

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[2] Citizens was chartered in 1887 as a Public Charitable Trust. A charitable trust is organized to serve private or public charitable purposes. A charitable trust is usually a non-profit organization which has to account for its activities (especially financial) to the government. There is normally an obligation to register a non-profitable charitable organization as the public is entitled to some oversight of organizations that wish to act for the public good. Citizens is generally treated as if it were a municipal utility.

[3] A municipally owned utility may be removed from the jurisdiction of the commission for the approval of rates and charges and of the issuance of stocks, bonds, notes, or other evidence of indebtedness, if the municipal legislative body adopts an ordinance removing the utility from commission jurisdiction. (IC 8-1.5-3-9.1).

[4] Retail sales are typically categorized by class of customer, i.e., residential, commercial and industrial customers. The designation "other" refers to sales to public authorities, i.e., governmental entities.

Total Sales (Dth) by Class for the Four Largest Gas Utilities in Indiana - 2004

Utility	Residential	Commercial	Industrial	Other	Total
Citizens Gas	23,018,806	12,969,010	1,825,533	-	37,813,349
Indiana Gas	44,661,000	19,108,000	565,000	-	64,334,000
NIPSCO	57,675,495	23,057,382	15,566,256	213,256	96,512,389
SIGECO	7,937,903	3,610,387	500,835	4,881	12,054,006
Total	**133,293,204**	**58,744,779**	**18,457,624**	**218,137**	**210,713,744**

Source: IURC Company Annual Reports on file with the IURC

The Natural Gas Market

2004–2005 Winter Market Conditions

Natural gas supplies meet one-fourth of the United States' energy needs. As a result of the deregulation and commodization of natural gas, market conditions now impact residential, commercial, and industrial consumers almost immediately. This past winter again proved this economic reality.

Market indicators for the 2004–2005 heating season suggested that gas bills were going to be higher than for the prior heating season because of increasing demand and prices. Anticipating this scenario, all of the major gas utilities conducted public relations campaigns to warn their customers that gas bills would likely increase, perhaps significantly, from the prior year. Customers were told that with a return of normal weather, increases in the average price of gas alone would raise gas bills over those of winter 2003–2004.

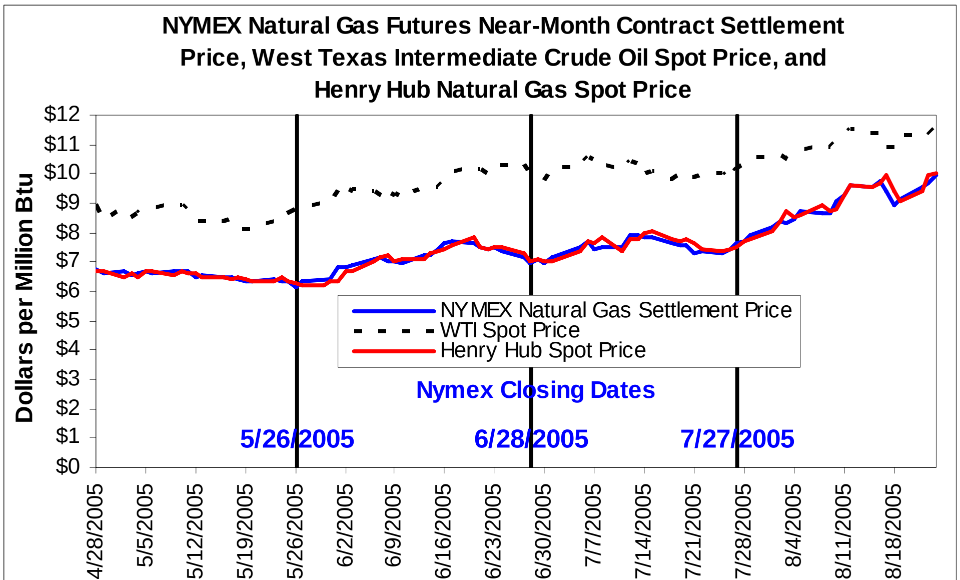
Fortunately for consumers, the winter of 2004-2005 was about what was expected. Winter temperatures for 2004-2005 were above average in the West, average in the Midwest, and average to below average in the East. However, several cold snaps in the East and Northeast helped to drive and sustain elevated prices. Natural gas in storage across the country was at a five year high at the start of the heating season and stayed well within the five year historical range for the remainder of the winter.[5]

Hurricane activity in the Atlantic Ocean was nothing short of incredible in the late summer and fall of 2004. Three different hurricanes made landfall and Ivan, in particular, greatly impacted the natural gas industry. As Ivan slammed the Federal offshore Gulf of Mexico producing region, 6.5 billion cubic

[5] EIA Natural Gas Weekly Storage Update as of July 21, 2005

feet per day of production was temporarily taken off-line.[6] Damage to natural gas producing infrastructure in the Gulf was significant.

Another factor that increased the price for natural gas was the threat of a reduction in the oil supply because of the continued U.S. involvement in Iraq. All of these variables converged to put upward pressure on gas prices, causing them to increase from less than $5.00 per Mcf [7] in September 2004 to over $9.00 per Mcf by November 2004. Prices tended to relax throughout the winter. The following graph indicates more recent futures activity.



Note: The West Texas Intermediate crude oil price, in dollars per barrel, is converted to $/MMBtu using a conversion factor of 5.80 MMBtu per barrel. The dates marked by vertical lines are the NYMEX near-month contract settlement dates.
Source: NGI's *Daily Gas Price Index* (http://Intelligencepress.com)

6 EIA Natural Gas Weekly Update as of September 23, 2004
7 For purposes of this Report, 1 Dekatherm (Dth) = 1 thousand cubic feet (Mcf) = 1 MMBtu.

Although sharp increases in residential heating bills were evident in the 2004–2005 winter season they were still slightly below the level seen during the 2000–2001 winter. During that winter, very low storage levels at the onset of the season and a cumulative slump in new supply capacity caused an even sharper spike in natural gas prices.

Market Projections for Gas Prices and Demand

A competitive market determines gas prices. Unfortunately for gas consumers, gas prices can be expected to continue to reflect price volatility over the next few years as gas prices respond to economic incentives and cycles to ensure sufficient and reliable gas supply.

Gas prices during the decade of the 1990s were stable, fluctuating around $2.00 per Mcf. The price spike of the 2000–2001 heating season was the most dramatic run-up in gas prices in history with prices increasing from their historical low of $2.00 to almost $10.00 per Mcf. This increase in wholesale prices quickly resulted in a significant increase in gas production that expanded the supply of natural gas for the 2001–2002 winter. The resulting increased inventory of natural gas was met with reduced industrial demand because of the prior season's high prices and warmer than normal weather which reduced demand by all customers. Natural gas prices responded to the over supply situation by falling, which reduced not only the price but also the quantity of gas available for the 2002–2003 winter as gas rigs shut down in response to falling prices. As noted in the previous section, the storage of gas across the country was at a five year high at the beginning of the heating season and remained well within the five year historical range for the rest of the winter.

The commodity price of natural gas has been increasing all over North America. There are both supply and demand explanations for this. First, aggregate demand for natural gas has been growing and is expected to increase by about 2.3% during 2005[8]. This is being driven by expanding economic growth across the United States. Real Gross Domestic Product (GDP) grew 3.5% per year during the first quarter

[8] From the Energy Information Administration's Short-Term Energy Outlook published June 2005

of 2005.[9] Economic growth generally indicates increased natural gas use especially from manufacturing activities.

Second, the North American natural gas markets are changing. The annual volume of natural gas that the U.S. imports from Canada is expected to remain relatively flat for the foreseeable future because of growing Canadian demand for natural gas coupled with diminishing production in Western Canada. Net U.S. exports to Mexico continue to rise and that trend likely will continue through 2006[10].

There are a few other supply concerns affecting the gas markets. Natural gas prices closely trend oil prices. Even though the oil and gas markets are separate, the prices for these two commodities move together because of inter-fuel competition in the industrial and power generation sectors. Thus the recent $60 per barrel world oil price is helping to support the $7.50 per Mcf gas prices this summer.

Today, the vast majority of the U.S. gas supply comes from traditional land-based and offshore supply areas in the U.S. and Canada. Domestic natural gas production is expected to grow about 0.9% in 2005, as was the case in 2004[11]. Well drilling activities will remain high this year. However, production levels from existing wells continue to decline which basically negate gains from the increased total number of producing wells.[12] Researchers at the National Oceanic and Atmospheric Administration (NOAA) are forecasting well above normal hurricane activity in the Atlantic Ocean for the 2005 Atlantic Hurricane Season (June 1 to November 30), including the considerable activity that has already occurred[13]. As was previously stated, hurricanes can disrupt the production of natural gas on off-shore drilling platforms.

Gas demand is projected to increase at an average annual rate of 1.7 percent between 2003 and 2025 primarily because of rapid growth in the electric generation sector. Gas continues to be the fuel of choice for electric capacity additions. The natural gas share of electricity generation is projected to

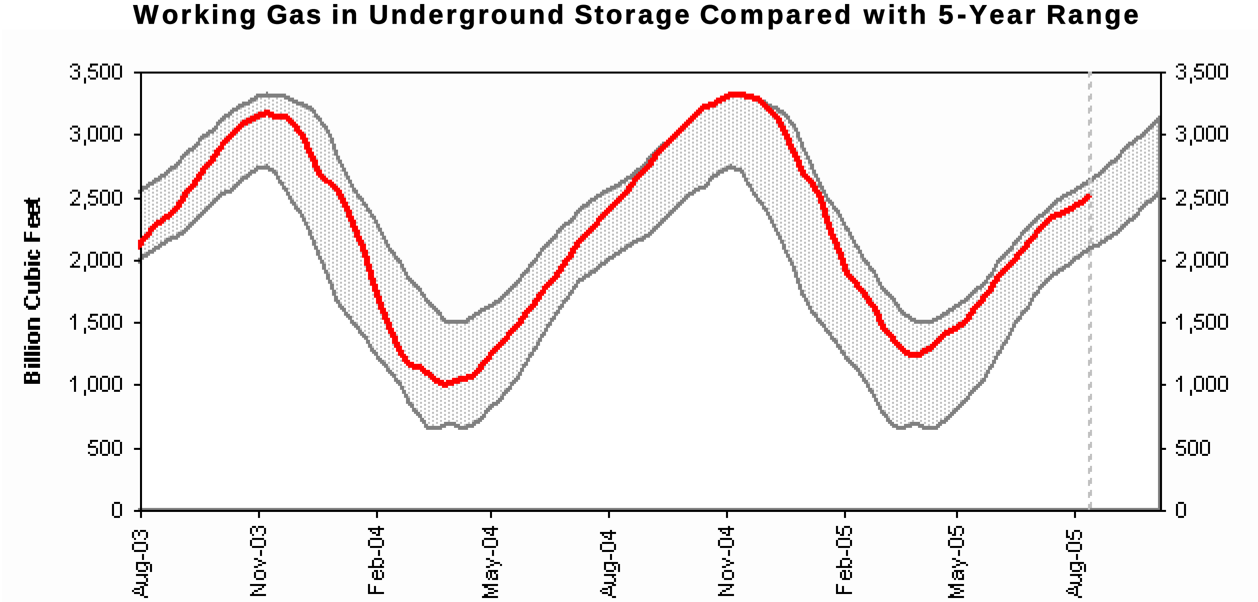
[9] From the Bureau of Economic Analysis released June 26, 2005
[10] From the Energy Information Administration's Annual Energy Outlook 2005 with Projections to 2025
[11] From the Energy Information Administration's Short-Term Energy Outlook published June 2005

[12] In general, a natural gas well will typically produce less and less gas each year over its useful production life.
[13] NOAA's National Weather Service Climate Prediction Center.

increase from 17 percent in 2003 to 24 percent by 2025, including generation by electric utilities, IPPs[14] and CHP[15] generators.[16]

Today the market is still nervous about gas prices and supply and this concern is likely to continue over the near-term. The gas industry has recently been operating at the tight end of the gas supply curve. As production nears capacity, the price responses to changes in demand or supply intensify. For example, if production is at its peak and demand increases, prices will increase far more than if idle capacity existed. The tight supply situation, gas price volatility, and higher gas prices are expected to persist.

Working Gas in Underground Storage Compared with 5-Year Range



Notes: A weekly record for March 8, 2002, was linearly interpolated between the derived weekly estimates that end March 1 and the initial estimate from the EIA-912 on March 15. The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2000 through 2004.
Source: Weekly storage values from March 15, 2002, to the present are from Form EIA-912, "Weekly Underground Natural Gas Storage Report." Values for earlier weeks are from the Historical Weekly Storage Estimates Database, with the exception of March 8, 2002.

[14] Independent Power Producers ("IPPs") are entities other than the electric utility in the area that produce electric power. The term is synonymous with "non-utility generation", also known as "NUG".
[15] Combined Heat and Power ("CHP") means the simultaneous generation of heat and electricity in a single plant. CHP can be used for district heating or industrial processes.
[16] Energy Information Administration's Annual Energy Outlook 2005.

All Volumes in Bcf	Current Stocks 8/19/05	One-Week Prior Stocks 8/12/05	Implied Net Change from Last Week	Estimated Prior 5-Year (2000-2004) Average	Percent Difference from 5 Year Average
East Region	1,452	1,406	46	1,417	2.5 %
West Region	377	372	5	330	14.2%
Producing Region	746	737	9	692	7.8%
Total Lower 48	2,575	2,515	60	2,439	5.6%

Source: Energy Information Administration: Form EIA-912, "Weekly Underground Natural Gas Storage Report," and the Historical Weekly Storage Estimates Database. Row and column sums may not equal totals due to independent rounding.

Natural gas in storage was at a five year high at the start of the heating season and stayed within the five year historical range for the remainder of the winter. As of August 19, 2005, total working gas is about 6% greater than the 5 year average.

As future demand for natural gas grows, it may become necessary to increase the development and utilization of non-traditional natural gas sources such as Alaskan gas, deep off-shore gas, and imported liquefied natural gas. Increasing natural gas supplies will help boost economic development while ensuring more stable prices for natural gas customers.[17]

Commission Actions Addressing Price Volatility and Supply Reliability

Intensified Commission Review of Gas Prices and Supply

As part of its normal course of business, the Commission monitors gas prices in the Gas Cost Adjustment (GCA) proceedings[18] for gas utilities under its jurisdiction. The scrutiny within these proceedings by both the Commission and the Office of Utility Consumer Counselor (OUCC) has increased dramatically over the last few years with the volatility in natural gas prices. In its orders, the

[17] Energy Information Administration's Annual Energy Outlook 2004.

[18] A gas cost adjustment (GCA) is an adjustment to effective rates which reflects the fluctuating cost of purchased gas. LDCs are allowed to pass-through the cost of gas and may not profit from this pass-through. The GCA statute may be found at I.C. 8-1-2-42.

Commission has encouraged utilities to explore innovative ways to control gas prices using strategies such as hedging, fixed and ratable purchases, and efficient use of storage.

In response to the Commission's interest in the issue of gas price volatility, many utilities have begun to include testimony on their price mitigation efforts as part of their normal filings in GCA proceedings. Information currently being provided by LDCs includes gas procurement strategies, gas purchasing targets by type of contract, storage options, and price projections. This information has been beneficial to Commission staff in the analysis of each GCA case.

Natural Gas Forum 2005

On July 29, 2005, the Commission conducted the annual Natural Gas Forum (Forum). The Commission has held these forums since 2001 in order to assess the following: 1) what Indiana utilities have done to secure gas supply and control the price of gas for the upcoming winter heating season, 2) what future actions utilities intend to take to mitigate the effects of higher gas costs and price volatility on customers, and 3) what joint efforts the OUCC, IURC, and LDCs can engage in to inform the public about current market conditions for gas and actions customers can take to maintain better control over their gas bills. The format of this year’s Forum was somewhat different than the previous four. Instead of being held over a period of two days, it consisted of one day with the following discussion panels: 1) unique issues facing small LDCs, 2) gas purchasing, portfolio management, and the role of the marketer, and 3) efficiency, conservation, and weatherization. A future date will be set closer to the heating season in order for the utilities to return to discuss gas prices.

The Forum was led off by a presentation by Ken Costello of the National Research Regulatory Institute discussing an overview of current natural gas issues from a national perspective. Mr. Costello also acted as the moderator for all three panels. The panel of small LDCs consisted of representatives of Ohio Valley Gas, Midwest Natural Gas, Pinnacle Energy, and Lawrenceburg Gas Company. Panel two consisted of representatives of NIPSCO, Vectren, Citizens, Proliance, NiSource. The final panel consisted of representatives of American Gas Association, NIPSCO, Citizens, and Community Action of Greater Indianapolis.

NIPSCO's DependaBill Program

The Commission approved a fixed gas bill (FGB) proposal by NIPSCO for a three-year trial period on July 3, 2002.[19] This program permits residential and commercial customers to fix their monthly gas bills payable to NIPSCO for an annual period regardless of the change in the price of natural gas or the weather's impact on consumption during a twelve-month period.[20] The FGB was marketed to customers as "DependaBill."

Late in 2004, NIPSCO filed a petition to amend the Commission's original FGB order. NIPSCO's contract with its unaffiliated partner in the FGB Program, WeatherWise, was terminated in the fall of 2003. Up to that point, WeatherWise provided direct marketing for the FGB Program and devised individualized quotes for interested customers. WeatherWise was unable to perform its contractual obligations due to financial problems so NIPSCO took over those roles during the 2003-2004 heating season. Because the original Order did not provide for any entity other than WeatherWise to be compensated for marketing and related services, the Commission approved an amendment that permitted either NIPSCO or its subcontractor to charge the entire Program Fee of up to 10% to accommodate the exit of Weatherwise from the FGB Program. The original order was also amended to allow for electronic enrollment by customers.[21]

Currently, customers can either contact NIPSCO and have the Company determine the price at which their bill will be fixed for a specified period, typically twelve months, or alternatively, NIPSCO will send customers a price quote for service during its marketing campaigns. NIPSCO provides detailed information to each prospective DependaBill customer concerning his or her rights and responsibilities under the program, including a disclaimer that the customer will not benefit from any reduction in the cost of gas commodity during the enrollment period. After receiving and reviewing their quote, a customer

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[19] Cause No. 42097, approved July 3, 2002, approved a Fixed Gas Bill service offering for NIPSCO. The Company changed the name of the program to DependaBill prior to actual implementation.

[20] This service differs from NIPSCO's Budget Billing Plan because it does not require a "true-up" at the end of the annual period, and from its Price Protection Plan, because bills still vary based on consumption even though a unit price for an annual period has been fixed.

[21] Cause No. 42097, Petition to Amend Order, approved December 22, 2004.

can enroll in the program by either returning a signed enrollment form by mail or fax, or by submitting their consent to NIPSCO by means of the Company's website. One of the conditions of the FGB Program is that a customer can be involuntarily dropped from the program if the customer uses 15% more gas than the customer would normally use. Additional usage due to colder weather will not result in any customers being involuntarily dropped.

Currently NIPSCO has approximately 11,900 customers enrolled in the DependaBill program. The program has been steadily growing since its introduction late in 2002, with 1,600 customers at the end of that year, to 6,900 by the end of 2003, and 10,400 by the end of 2004.

On February 18, 2005, NIPSCO filed a Petition to modify and extend the FGB Program.[22] Subsequently, on July 13, 2005, NIPSCO filed a Petition, docketed as Cause No. 42884, to renew and modify NIPSCO's Alternative Regulatory Plan (ARP) and submitted a Settlement Agreement, signed by the parties in Cause No. 42884, which contains proposed modifications to the FGB Program. These changes include continuous customer enrollment, the ability of customers to initiate contact and enroll in the FGB Program over the telephone, and an increase in the cap on FGB enrollees from 30,000 to 45,000 customers. A prehearing conference for Cause No. 42884 was held on August 24, 2005. A settlement hearing for Cause No. 42884 is scheduled for October 3, 2005. If there are opposing parties, the hearing will take place October 26, 2005.

NIPSCO's Gas Cost Adjustment (GCA)

In its Order of August 18, 1999 in Cause No. 41338, the Commission approved a proposed redesigned mechanism for NIPSCO's GCA consisting of two parts: a monthly commodity filing and an annual demand charge filing. Under this mechanism, NIPSCO makes a monthly commodity filing which will determine the gas commodity component of the GCA factor for a calendar month with twelve monthly filings being made each year. NIPSCO began making these monthly commodity filings on September 1, 1999. The Company makes its annual filing three working days prior to September 1 of

[22] Cause No. 42800, Petition to Modify and Extend Fixed Gas Bill Program, filed February 18, 2005.

each year to determine the demand component of its gas costs for the twelve months beginning November 1 of each year. On August 27, 2004, NIPSCO filed its sixth annual filing: Cause No. 41338 GCA 6.

On October 3, 2004, NIPSCO proposed that the rates as contained in its August 27 Petition be made effective, on an interim basis, subject to refund because the evidentiary hearing in this matter will not be scheduled until 2005. The Company stated that the estimated GCA demand costs of $81,756,149 represent a one percent increase over the total GCA costs of $80,873,131 as approved by the Commission's Order of August 18, 2004 in GCA 5. The OUCC and the intervenors did not object to the Company's request. On October 20, 2004, the Commission issued an Interim Order in Cause No. 41338 GCA 6 approving NIPSCO's rates on an interim basis and subject to refund.

The Commission held a Public Evidentiary Hearing on March 2, 2005 in Cause No. 41338 GCA 6 and a final order, which affirmed the Interim Order, was issued on August 24, 2005.

NIPSCO remains committed to the positive changes that resulted from previous Commission Orders, such as: 1) improved communication and information exchange between NIPSCO, the OUCC's auditors, and Commission staff, 2) ongoing meetings between the Parties and Commission staff, which have resulted in significant improvements to monthly and annual GCA filings, and 3) increased volatility mitigation, which has been reflected in customers' bills.

Customer Deposit Rulemaking

On June 1, 2004, the Commission published a Notice of Intent to Adopt a rulemaking on customer rights and responsibilities for all utility industries. The Notice of Proposed Rulemaking was issued by the Commission on July 21, 2004.[23] All utility industries were included in this rulemaking. The Commission held hearings and received extensive comments on this rulemaking.

Some provisions of the proposed rule proved to be controversial and there was inadequate time to develop a robust final rule under normal rulemaking timelines. Consequently, that proposed rule was withdrawn by the Commission. On June 1, 2005, the Commission published a Notice of Intent to adopt a rulemaking concerning utility deposits, reconnections, and disconnections solely for gas utilities by

[23] Notice of Proposed Rulemaking (IURC RM #04-02).

amending existing regulations contained in 170 IAC 5-1-15 and 170 IAC 5-1-16. A Notice of Proposed Rulemaking was approved by the Commission on August 10, 2005 and a hearing to receive comments on the proposed rule has been set for October 4, 2005.

Other Gas Issues Affecting Indiana

GCA Timeframes–semi-annually, quarterly, and monthly

The majority of Indiana's smaller LDCs continue to file traditional quarterly GCA petitions. Only two companies, Kokomo Gas and Fuel Company and Northern Indiana Fuel & Light Company, continue to implement gas cost adjustments on a semi-annual basis.

Currently, two LDCs, NIPSCO and Valley Rural Utility Company, use a monthly GCA factor with an annual hearing to discuss important issues pertaining to the previous and upcoming years, to true-up any under or overestimated costs, and to present known demand costs for the upcoming year. NIPSCO's and Valley Rural's GCA mechanisms, approved under the Alternative Utility Regulation statute[24], allow monthly flexing up or down based on prevailing market conditions.[25] In addition to the annual hearing requirements, both LDCs are required to file monthly informational filings with the Commission showing commodity prices and GCA factors to be implemented for the upcoming month. NIPSCO, an investor-owned LDC, files quarterly earnings information. Valley Rural Utility Company, a not-for-profit, recovers its incremental gas costs over base rates on a monthly basis as approved in its Alternative Regulatory Plan (ARP). Recoverable costs are subject to a cap, and will be subject to review in an annual gas supply proceeding that addresses the components of gas supply for the upcoming year and seeks final approval of the gas supply costs charged during the preceding twelve months. As of April 2005, the Company was providing service to 271 customers.

[24] Indiana Code § 8-1-2.5 Alternative Utility Regulation
[25] Cause No. 41338 ARP, NIPSCO; Approved 12/1/1998 and Cause No. 42115 Certificate of Need and ARP, Valley Rural Utility Company; Approved 5/8/2002

Three of Indiana's major LDCs continue to file quarterly GCAs, but are allowed to adjust their approved GCAs monthly. IGC and SIGECO, both subsidiaries of Vectren Energy Delivery of Indiana, are allowed to "flex," or adjust, their GCA factors down from Commission approved maximum factors, or caps, once a month in an effort to more closely reflect current gas prices. These flex-down mechanisms are approved on a cause-by-cause basis. Additionally, Citizens petitioned to file quarterly with monthly adjustments to its GCA factors on July 26, 2002.[26] Citizens may flex its monthly GCA factor up or down, with a $1.00 per Dth maximum flex. The mechanism was initially approved for a test period of one-year. On April 29, 2003, representatives of Citizens, the OUCC, and the Commission staff met to review the performance of the GCA monthly flex mechanism. As a result of that meeting, the parties filed a report to the Commission on August 15, 2003, and an amended settlement agreement on the GCA flex issue on October 9, 2003. The Commission subsequently issued an order on March 17, 2004, which extended use of the flex mechanism through August 2005 (GCA 86). With the approval of this change for Citizens, the majority of gas bills rendered in Indiana reflect GCA factors that change monthly.

Gas Cost Incentive Mechanisms

A Gas Cost Incentive Mechanism (GCIM) provides risks and rewards to LDCs for gas supply acquisition performance compared to a market standard (benchmark). Benchmark prices reflect natural gas commodity prices for geographic locations representative of the supply source where the gas was purchased, and are usually calculated monthly. The benchmark price is then divided by the actual amount of gas purchased to determine the benchmark dollars. If an LDC's actual natural gas commodity purchases are above or below the benchmark dollars, predetermined percentages of the positive or negative differentials are shared among the utility and its customers. For example, if the actual gas purchases are slightly below the benchmark dollars, a higher percentage of the savings goes to the customers; however, if the actual gas purchases are a greater percentage below the benchmark dollars, a higher percentage of the savings differential is shifted to the LDC. This works similarly on the other side

[26] Cause No. 37399 GCA 75, Citizens Gas & Coke Utility, approved September 4, 2002.

of the benchmark level. The customers absorb costs that are only slightly higher than the benchmark; however, if costs exceed the benchmark by a greater amount, a higher percentage of the differential is shifted to the LDC.

NIPSCO has had a GCIM in place since 1997, which was approved as part of its ARP.[27] Through various causes, the NIPSCO GCIM has been modified and continued in effect. . Further modifications to the NIPSCO GCIM are proposed in Cause No. 42844, which was filed on July 13, 2005, and is a request by NIPSCO to make comprehensive changes to the ARP approved in 1997. The parties to Cause No. 42844 have submitted a settlement agreement to the Commission. A settlement hearing for Cause No. 42884 is scheduled for October 3, 2005. If there are opposing parties, the hearing will take place October 26, 2005. IGC, SIGECO, and Citizens have implemented GCIMs as part of an ARP approved on July 24, 2002.[28]

Pipeline Safety Activity

The Pipeline Safety Division of the IURC has the responsibility of enforcing state and federal safety regulations for Indiana's gas pipeline facilities. The Division operates in partnership with the United States Department of Transportation Office of Pipeline Safety under a certification agreement. Their mission, to ensure the safe, reliable, and sound operation of Indiana's pipeline transportation system, is accomplished largely through inspections, investigations of pipeline accidents, continuing training, and outreach.

President Bush signed the Pipeline Safety Improvement Act of 2002 (the "Act") on December 17, 2002. Several provisions included in the Act continue to impact the State of Indiana. With improved public safety as the intended outcome, additional efforts are being committed by both pipeline operators and the IURC to ensure compliance with the law.

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[27] Cause No. 40342, Northern Indiana Public Service Company, approved on October 8, 1997.
[28] Cause No. 42233 ARP which has been consolidated with Cause Nos. 37394 GCA 50-S1 and 37399 GCA 50-S1.

The law mandated that all operators of natural gas transmission lines have an integrity management program in place for high consequence areas by December 2004.[29] Indiana's intrastate gas companies operate 1,886 miles of transmission pipeline. Not all of these pipelines are located in high consequence areas, as that term is defined in the rule. The impact of a gas pipeline rupture varies based on its size, operating pressure, and proximity to people. The rule requires operators to use these factors, along with other factors, including the calculation of heat-impacted zones, to identify high consequence areas.

For pipelines located in high consequence areas, baseline integrity assessments (determining the current physical condition of pipelines) began in June 2004 and must be completed December 2007 or 2012, depending on the facility's location, pressure, and diameter. Assessments may be made by utilizing in-line inspections (pigging), hydrostatic pressure testing, or direct assessment[30]. Gas operators are dedicating significant resources in order to comply with the regulations and will continue to do so. Costs are incurred for identifying pipeline segments in high consequence areas, setting up a framework for the company's program, conducting a baseline assessment of affected pipelines, conducting periodic assessment and evaluation, evaluating automatic shutoff and remotely controlled valves, data integration, and remedial action. The cost to gas utilities will be dependent partially upon the baseline assessment timeframe, the extent to which Indiana's facilities can be internally inspected, and other factors. The majority of transmission lines operated by Indiana local distribution companies will not accommodate an in-line inspection device and cannot be shut down to conduct a hydro test, so most operators must use direct assessment to determine the condition of the pipe.

Indiana's gas utilities and, in turn, its customers will also be affected by the manner in which interstate gas transmission operators conduct their integrity management programs. Unless adequate time is allowed and the assessment process is carefully managed, flow restrictions can significantly impact gas

[29]The U.S. Department of Transportation's Office of Pipeline Safety (OPS) issued a final integrity management rule on December 15, 2003, with updates published April 6, 2004, and May 26, 2004.
[30] Direct Assessment is a method that utilizes a process to evaluate certain threats (e.g., external corrosion, internal corrosion, and stress corrosion cracking) to a pipeline's integrity. It includes data gathering, indirect and direct examination of the pipeline, and post assessment evaluation.

supply and cost to customers. There also exists the potential for critical supply interruptions, as this law applies to interstate transmission companies that serve the Indiana utilities. In Indiana there are over 5,000 miles of interstate gas transmission pipelines.

The enforcement of the Integrity Management rule requires additional training for the IURC's Pipeline Safety Division. The Transportation Safety Institute, which is the training agency within the U.S. Department of Transportation (US DOT), has developed a series of courses, which inspectors are to complete before conducting Integrity Management inspections. The Pipeline Safety Division staff conducting these specialized inspections is in the process of completing these courses. Federal protocols will be used during the inspection process. Although Indiana's intrastate transmission facilities do not represent the bulk of jurisdictional piping for the Pipeline Safety Division, the nature of the inspections will require the Division to dedicate considerable resources to integrity management enforcement due to the complexity of the regulation. Work has also begun to determine the appropriate format for integrity management at the distribution level. In Congressional testimony presented last year, the US DOT Inspector General stated that distribution facilities should be subject to integrity management. Congress then directed the US DOT/ OPS to respond. A report to Congress must be submitted no later than December 2005. Currently a number of work groups are involved in collecting and analyzing existing data, programs, and regulations. The threats associated with gas distribution facilities are different from those for transmission facilities. It is anticipated that additional rules and/or standards for distribution facilities will be the outcome of this effort. Since Indiana operators have over 70,000 miles of distribution facilities, the outcome of this effort will significantly impact those operators and the Pipeline Safety program.

The Pipeline Safety Act also addresses pipeline outreach programs. Among other things, it requires operators to review and revise existing public education programs. The first step in this process occurred in December 2003 when operators conducted a self-assessment of their public education plans and submitted the assessments to the IURC Pipeline Safety Division and OPS headquarters in Washington. A National Standard (API Standard RP 1162) has been incorporated by reference into federal pipeline safety regulations. This Standard sets forth specific requirements regarding the message, methodology, and frequency of communication with target audiences. In 2005, pipeline operators and local distribution companies formed the Indiana Pipeline Awareness Association (INPAA), whose purpose is to provide public awareness compliance tools for the industry. The Pipeline Safety Division will enforce this as part of its inspection process. Compliance deadline for this particular regulation is June 20, 2006.

The Act also requires the Secretary of Transportation to encourage the adoption of practices set forth in the best practices report entitled "Common Ground."[31] Indiana's Pipeline Safety Division is taking an active role in following through with the requirements of these provisions. It continues to work with state and federal liaisons and the Board, staff, and members of the Indiana Underground Plant Protection Services to encourage the adoption of best practices and involvement in the Common Ground Alliance. The Division intends to do everything in its power to develop and strengthen Indiana's underground protection laws and damage prevention programs, as third-party damage continues to be the leading cause of pipeline accidents, both statewide and nationwide.

The Act includes additional requirements for Indiana's gas operators. It requires all operators to develop and complete qualification of pipeline personnel programs (Operator Qualification Programs); and requires regulators to complete inspections of such programs by December 2005. Inspections of the Operator Qualification Programs have begun, and data gathered during the inspection process is being entered into a federal OPS database. This data will be used to develop a report for Congress concerning the progress of Operator Qualification Programs. In accordance with the mapping provision of the Act, natural gas transmission operators provided data to the National Mapping System and will update this information as necessary. Finally, the Act required the Secretary of Transportation to work with the Federal Communications Commission, facility operators, excavators, and one-call notification systems

[31] The Common Ground study was developed in response to a directive from Congress to the US DOT. The directive required the development of best practices for preventing damage to underground facilities and assuring their safe operation. The result was the comprehensive Common Ground study and the subsequent establishment of the Common Ground Alliance – a non-for profit organization that fosters communication and the adoption of best practices.

for the establishment of a nationwide toll-free 3-digit telephone number system to be used by state one-call programs. On March 10, 2005, the Federal Communications Commission designated 811 as the nationwide number for contractors and others to call before conducting excavation activities. The FCC ordered that the number be operational two years from publication in the Federal Register. The costs to implement three-digit dialing for One Call are still being determined.

Competitive Initiatives in Natural Gas

National Overview

Since the implementation of the Natural Gas Policy Act of 1978, Congress began a process that ended federal control over the price of gas at the wellhead. This process also set in motion a series of public policy changes by FERC and state regulators that has culminated in “customer choice” programs in the natural gas industry.

Natural gas choice is similar to choosing a long distance telephone company. The local utility continues to own and maintain the pipes that deliver the gas service to consumers’ homes or businesses, but consumers can choose the company that provides their natural gas. In today’s competitive market, suppliers can offer a variety of prices, incentives, or services to gain business. Therefore, customers have the opportunity to comparison shop for the best deal, just like they do when they buy a car, home, or their weekly groceries. Since 1995, several states have enacted legislation or rules that allow residential customers and small commercial customers to purchase gas from someone other than the local gas company.

Currently, choice programs are operating in nineteen states and the District of Columbia. About 3.9 million residential customers participate in choice programs. Participation rates vary dramatically across programs, ranging from those that attract few customers to participation rates of 30-50 percent. Some states have expanded their programs to include more eligible customers while others have died, strived to survive, or simply reached a plateau.

Nationally, there has been a decline in the number of marketers over the past few years. The increase in gas prices in the winter of 2000–2001, the financial problems of energy trading companies, and the increased difficulty of marketers to make a profit all contributed to the reduced number of marketers. The gas business is a low profit-margin business where marketers are selling a commodity to a mass market. Marketers must purchase gas and transportation in the same markets as LDCs. Some marketers have discovered that customer service and marketing costs cut too deeply into their profits.[32]

Choice programs continue to evolve over time as circumstances change. These programs still provide a challenge to LDCs, marketers, and regulators as they change in size and scope in response to market realities over which no one has control. The learning process and reconfiguring of choice programs can be expected to continue.

Status of Customer Choice in Indiana

NIPSCO's Customer Choice Program

The Commission approved NIPSCO's "Choice" program in its Order of October 8, 1997, in Cause No. 40342. The utility began phasing in its customer choice program in April 1998. The eligibility numbers increased from 50,000 residential and 1,500 business customers to include the entire customer base of 647,000 and 56,000, respectively. The Choice program's enrollment caps are 150,000 residential customers and 20,000 commercial customers. NIPSCO estimated that all of its customers would have access to unbundled service by January 1, 2005 (no actual figures have been provided yet).

The company reports that participation dropped substantially over the 2000–2002 time period, with more than 12,000 residential customers enrolled in July 2000, but only 4,766 residential customers in September 2002 after the only active supplier stopped its customer enrollment activities. Nationally during this time, the growth rate for residential customers that had access to choice programs was slowed due to the saturation of prime markets, waning marketer interest, and volatility in the natural gas and

[32] The National Regulatory Research Institute, *Survey on the Features and Regulatory Oversight of Gas Choice Programs*, NRRI 03-02, February 2003, pp. 1-2.

electricity markets. NIPSCO made a concerted effort to revitalize the program in late 2002 that led to three new suppliers entering the program. As of April 2004, almost 59,000 customers (mostly residential but some commercial as well) were enrolled and eight suppliers were participating. On July 13, 2005, NIPSCO filed a Petition, docketed as Cause No. 42884, to renew and modify NIPSCO's ARP and submitted a Settlement Agreement, signed by the parties in Cause No. 42884, which contains proposed modifications to the customer choice program. A prehearing conference for Cause No. 42884 was held on August 24, 2005. A settlement hearing for Cause No. 42884 is scheduled for October 3, 2005. If there are opposing parties, the hearing will take place October 26, 2005.

TABLE 2

STATUS OF NIPSCO CHOICE PROGRAM
As of May 2005

Customer Class	Total Customers 5/31/2005	Enrollment Caps for Choice Program		Participating		
		Cap	Percentage of Total	Total	Percentage of Eligible Customers	Percentage of Total Customers
Residential	647,439	150,000	23.2%	50,051	33.4%	7.7%
Business	56,630	20,000	35.3%	8,729	43.6%	15.4%
Total	704,069	170,000	24.1%	58,780	34.6%	8.3%

Citizens' Alternative Regulatory Plan

Effective June 1, 2003, the Commission approved an ARP for Citizens. The utility cited an increasingly competitive energy environment in which market forces have replaced traditional regulation as the primary reason for the change. Implementation of its unbundled tariff will result in most commercial and industrial customers being able to choose their gas supplier, with Citizens remaining one of the supplier choices. Key elements of Citizen's proposal included: 1) the phasing in of new unbundled services, 2) affiliate guidelines that serve as ethical codes of conduct between the utility and other third-party suppliers, 3) Citizens acting as the supplier of last resort, 4) new service offerings for third-party suppliers, 5) no increase in its current rates, and 6) immediate service changes for large commercial and industrial users using over 50,000 Dth annually in the first year. Currently, customer choice is not available to Citizens' residential customers, although the unbundled tariff and rate design will make its implementation in the future much easier.

COMBINED ANALYSIS OF GAS SALES DATA

CITIZENS GAS, INDIANA GAS, NIPSCO, & SIGECO

Total Sales By Class (1,000 Dth)	2004	2003	2002
Residential	133,293	141,561	142,848
Commercial	58,745	63,501	58,252
Industrial	18,458	17,441	18,065
Other	218	5,579	6,397
Total	**210,714**	**228,082**	**225,562**
Total Transportation By Class (1,000 Dth)			
Residential	4,935	4,914	1,476
Commercial	18,242	16,882	17,894
Industrial	212,898	198,991	206,996
Other	4,427	1,871	6,043
Total	**240,502**	**222,658**	**232,409**
Total Throughput By Class (1,000 Dth)			
Residential	138,228	146,474	144,324
Commercial	76,987	80,383	76,146
Industrial	231,356	216,432	225,061
Other	4,645	7,449	12,440
Total	**451,216**	**450,738**	**457,971**
Percent Transportation to Throughput			
Residential	3.57%	3.35%	1.02%
Commercial	23.69%	21.00%	23.50%
Industrial	92.02%	91.94%	91.97%
Other	95.30%	25.11%	48.58%
Total	**53.30%**	**49.40%**	**50.75%**

ANALYSIS OF GAS SALES DATA FOR 2002, 2003, & 2004

CITIZENS GAS AND COKE UTILITY

	2004	2003	2002
Revenues By Customer Class			
Residential	$ 214,080,944	$ 211,384,956	$ 176,765,066
Commercial & Industrial	119,382,304	120,607,508	91,663,893
Other	26,598,936	2,056,853	3,439,265
Totals	$ 360,062,184	$ 334,049,317	$ 271,868,224
Sales By Customer Class in Dth			
Residential	23,018,806	24,725,447	24,130,546
Commercial & Industrial	14,794,543	16,754,624	15,910,105
Other	-	4,328,071	-
Totals	37,813,349	45,808,142	40,040,651
Revenues Per Dth			
Residential	$ 9.3003	$ 8.5493	$ 7.3254
Commercial & Industrial	$ 8.0693	$ 7.1985	$ 5.7614
Other	$ -	$ 0.4752	$ -
Average Rate	$ 9.5221	$ 7.2924	$ 6.7898

INDIANA GAS COMPANY, INC.

	2004	2003	2002
Revenues By Customer Class			
Residential	$ 450,041,811	$ 439,108,387	$ 350,567,161
Commercial & Industrial	179,265,153	173,232,908	138,229,744
Other	22,778,588	10,348,843	17,165,239
Totals	$ 652,085,552	$ 622,690,138	$ 505,962,144
Sales By Customer Class in Dth			
Residential	44,661,811	48,144,000	45,041,000
Commercial & Industrial	19,673,000	20,773,000	20,062,000
Other	-	-	-
Totals	64,334,000	68,917,000	65,103,000
Revenues Per Dth			
Residential	$ 10.0768	$ 9.1207	$ 7.7833
Commercial & Industrial	$ 9.1122	$ 8.3393	$ 6.8901
Other			
Average Rate	$ 10.1359	$ 9.0354	$ 7.7717

NORTHERN INDIANA PUBLIC SERVICE CO.

Revenues By Customer Class	2004	2003	2002
Residential	$ 553,581,349	$ 584,104,222	$ 469,273,275
Commercial & Industrial	311,811,314	348,415,891	224,251,029
Other	1,463,474	10,979,965	18,436,829
Totals	$ 866,856,137	$ 943,500,078	$ 711,961,133
Sales By Customer Class in Dth			
Residential	57,675,495	60,236,514	65,114,972
Commercial & Industrial	38,623,638	38,817,284	36,167,077
Other	213,256	1,243,411	6,392,301
Totals	96,512,389	100,297,209	107,674,350
Revenues Per Dth			
Residential	$ 9.5982	$ 9.6968	$ 7.2068
Commercial & Industrial	$ 8.0731	$ 8.9758	$ 6.2004
Other	$ 6.8625	$ 8.8305	$ 2.8842
Average Rate	$ 8.9818	$ 9.4070	$ 6.6122

SOUTHERN INDIANA GAS & ELECTRIC CO.

Revenues By Customer Class	2004	2003	2002
Residential	$ 73,626,024	$ 69,449,674	$ 64,421,116
Commercial & Industrial	33,787,288	33,786,368	28,147,654
Other	38,603	52,654	65,470
Totals	$ 107,451,915	$ 103,288,696	$ 92,634,240
Sales By Customer Class in Dth			
Residential	7,937,903	8,454,811	8,561,003
Commercial & Industrial	4,111,222	4,597,173	3,774,739
Other	4,881	7,221	407,160
Totals	12,054,006	13,059,205	12,742,902
Residential	$ 9.2752	$ 8.2142	$ 7.5249
Commercial & Industrial	$ 8.2183	$ 7.3494	$ 7.4568
Other	$ 7.9088	$ 7.2918	$ 0.1608
Average Rate	$ 8.9142	$ 7.9093	$ 7.2695

RESIDENTIAL GAS BILLS AS OF JANUARY 1, 2005
RANKED HIGHEST TO LOWEST AT 200 THERMS
IURC GAS DIVISION

Rank	Utility Name	150 Therms	200 Therms	250 Therms
1	South Eastern Indiana Gas Co.	$190.65	$250.45	$310.26
2	Lawrenceburg Gas Co. (Rate G-1)	$191.17	$248.34	$305.50
3	Valley Rural Utility Company (3)	$188.65	$247.95	$307.25
4	Aurora Municipal Gas	$181.10	$240.59	$300.08
5	Fountaintown Gas Company, Inc.	$182.41	$239.98	$297.55
6	Indiana Utilities Corporation	$182.32	$238.26	$294.20
7	Ohio Valley Gas Corp. (TXG)	$180.10	$235.80	$291.50
8	Ohio Valley Gas Corp. (ANR) (2)	$173.80	$227.40	$281.00
9	Lawrenceburg Gas Co. (Brookville)	$169.62	$221.12	$272.61
10	Boonville Natural Gas Corporation	$167.31	$219.08	$270.85
11	Ohio Valley Gas, Inc.	$166.42	$217.56	$268.70
12	Indiana Gas Company	$161.66	$209.70	$258.48
13	Community Natural Gas (1)	$158.81	$206.08	$253.36
14	Peoples Gas & Power Co. (4)	$158.68	$206.02	$253.35
15	Indiana Natural Gas Corporation	$155.90	$204.41	$252.92
16	Northern Indiana Public Service Co.	$151.81	$199.70	$247.60
17	Midwest Natural Gas Corp.	$149.52	$195.12	$240.72
18	Westfield Gas Corporation	$151.19	$193.87	$236.54
19	Chandler Natural Gas Corporation	$145.54	$191.54	$237.54
20	Citizens Gas & Coke Utility	$146.10	$190.49	$234.88
21	Northern Indiana Fuel & Light Co., Inc.	$144.21	$187.95	$231.70
22	Kokomo Gas and Fuel Company	$141.35	$182.98	$224.60
23	Switzerland County Natural Gas	$131.94	$173.19	$214.43
24	Southern Indiana Gas & Electric Co.	$132.67	$171.72	$211.52
25	Snow & Ogden Gas Company, Inc.	$75.20	$100.20	$125.20

This Gas Bill Analysis should be construed as an informative guideline. It is a snapshot in time. Gas rates change frequently, in some cases monthly, due to gas cost adjustments. Using this analysis to draw conclusions about a particular utility's performance would be difficult due to many factors such as utility size and resources, time since the last rate case, storage options, geographic location, base rates, customer density, and gas cost adjustment in effect at the time of bill calculation.

RESIDENTIAL GAS BILL COMPARISION (2001-2005)

BILLS CALCULATED BASED ON RATES IN EFFECT JANUARY FIRST OF EACH YEAR

RANKED HIGHEST TO LOWEST BASED ON 5 YEAR AVERAGE

IURC GAS DIVISION

		Consumption Level of 200 Therms					
Rank	**Utility Name**	**5 Year Average**	**2005 Bills**	**2004 Bills**	**2003 Bills**	**2002 Bills**	**2001 Bills**
1	Lawrenceburg Gas Co. (Rate G-1)	195.91	248.34	213.09	156.64	197.22	164.24
2	Boonville Natural Gas Corp.	194.65	219.08	196.18	172.63	205.70	179.66
3	Ohio Valley Gas Corp. (ANR) (2)	193.44	227.40	225.70	164.94	180.37	168.81
4	Westfield Gas Corp.	192.88	193.87	204.97	167.15	213.05	185.36
5	Indiana Utilities Corp.	189.21	238.26	209.20	150.89	189.05	158.65
6	South Eastern Indiana Gas Co.	188.71	250.45	211.19	147.09	172.41	162.41
7	Aurora Municipal Gas Utility	187.10	240.59	205.25	147.77	184.96	156.95
8	Ohio Valley Gas Corp. (TXG)	185.18	235.80	220.18	144.48	168.15	157.27
9	Lawrenceburg Gas Co. (Rate G-2)	183.36	221.12	211.84	138.18	179.40	166.26
10	Ohio Valley Gas Inc.	180.13	217.56	223.52	137.72	172.89	148.97
11	Northern Indiana Public Service Co.	179.82	199.70	181.31	179.35	127.81	210.91
12	Community Gas Corp. (Rate 1) (1)	179.71	206.08	199.96	145.77	205.47	141.26
13	Indiana Natural Gas Corp.	179.44	204.41	208.96	151.36	178.29	154.18
14	Peoples Gas and Power Co. (4)	172.06	206.02	216.02	121.94	162.00	154.34
15	Indiana Gas Co.	171.81	209.70	179.40	161.32	133.22	175.40
16	Community Gas Corp. (Rate 2) (1)	170.67	206.08	199.96	123.33	173.82	150.16
17	Fountaintown Gas Co.	168.87	239.98	139.58	144.86	180.32	139.60
18	Chandler Natural Gas Corp.	168.79	191.54	171.08	148.57	179.36	153.39
19	Switzerland County Natural Gas Co.	168.27	173.19	173.19	144.31	199.79	150.85
20	Midwest Gas Corp. (1)	166.48	195.12	205.12	125.25	155.57	151.34
21	Northern Indiana Fuel and Light Co.	164.69	187.95	170.11	141.90	192.85	130.65
22	Citizens Gas and Coke Utility	157.67	190.49	167.85	146.66	125.92	157.44
23	Kokomo Gas and Fuel Co.	149.53	182.98	165.80	131.60	154.01	113.27
24	Southern Ind. Gas & Electric Co.	143.32	171.72	154.84	146.42	108.80	134.82
25	Snow and Ogden Gas Co.	100.20	100.20	100.20	100.20	100.20	100.20

This Gas Bill Analysis should be construed as an informative guideline. It is a snapshot in time. Gas rates change frequently, in some cases monthly, due to gas cost adjustments. Using this analysis to draw conclusions about a particular utility's performance would be difficult due to many factors such as utility size and resources, time since the last rate case, storage options, geographic location, base rates, customer density, and gas cost adjustment in effect at the time of bill calculation.

AREAS SERVED

<u>Community Natural Gas</u>

Rate 1

Serving: Dale, Mariah Hill, Santa Claus and Gentryville

Rate 2

Serving: Owensville, Cynthiana, Holland, Worthington, Carlisle and Spencer

<u>Lawrenceburg Gas</u>

Rate G-1, <u>Lawrenceburg Division</u>

Serving: Greendale, Lawrenceburg, Rising Sun and West Harrison

Rate G-2, <u>Brookville Division</u>

Serving: Brookville

<u>Ohio Valley Gas Corp.</u>

ANR Consolidated Area

(**Formerly ANR**; ANR Pipeline System)

Serving: Ferdinand, Pennville, Portland, St. Anthony, St. Marks and St. Meinrad

(**Formerly PE**; Panhandle Eastern Pipeline System)

Serving: Deerfield, Fountain City, Lynn, Ridgeville, Saratoga, Union City and Winchester.

TXG; Texas Gas Transmission System

Serving: Cannelton, Connersville, Everton, Guilford, Lawrenceville, New Alsace, Sunman, Tell City, Troy and Yorkville

<u>Ohio Valley Gas, Inc.</u>

Serving: Dugger, Farmersburg, Hymera, Riley, Shelburn, Sullivan and Winslow

<u>Notes:</u>

1. Community Natural Gas Rates 1 and 2 were consolidated pursuant to Commission order in Cause No. 42452, dated 11/20/03.
2. Ohio Valley Gas "ANR" and "PE" service areas were consolidated pursuant to Commission order in Cause No. 40049, dated 11/09/95. The consolidated area was named "ANR" to distinguish it from the "TXG" service area.
3. Valley Rural Utility Co. began natural gas service in July 2003 and is not included in the 5 and 10 year averages because there is not enough data at this point in time.
4. Peoples Gas & Power Co., Inc. merged with Midwest Natural Gas Corp. in Cause No. 42246, dated 2/5/03. The customer groups of the merged company are split into Midwest Division and Peoples Division.

History of U.S. Gas Market Deregulation

1938 The National Gas Act (NGA)

The NGA created the Federal Power Commission (FPC) to regulate natural gas pipelines (but not wellhead prices). Rapid growth in the 1940s and 1950s outpaced pipeline expansion, which led to price volatility and supply shortages in some areas. Producers requested price caps, but the FPC said it did not believe it had the authority to set them.

1954 The Supreme Court determined the NGA should encompass the regulation of both pipelines and wellhead prices. This was known as the **Phillip's Decision**, and the court held that the primary aim of the NGA was the "protection of consumers against exploitation at the hands of natural gas companies."

This created an industry structure that consisted of price-regulated gas producers, who sold to price-regulated pipelines, who in turn sold gas on to local distribution companies (LDCs). LDCs then sold the gas onto end users (LDCs were regulated by state or local government agencies).

Price volatility was reduced by the Phillip's Decision, but it eventually caused supply shortages - it encouraged consumers to buy relatively cheap fuel but did not provide any incentive to producers to replace reserves.

1978 Natural Gas Policy Act

The Federal Energy Regulatory Commission (FERC) was created out of the old FPC and directed to reform natural gas pricing.

Essentially this was a reversal of the Phillip's decision as it allowed the deregulation of wellhead gas prices.

Production increased dramatically in response to pent-up demand which led to a gas surplus in the 1980s. However, a competitive market failed to develop, mainly due to the role pipelines played in the market. Since pipelines charged consumers enough to cover the cost of what they had to pay producers, there was no incentive for them to select the most competitively priced gas produced.

1985 FERC Order 436

This required pipelines to provide open access to transportation services allowing consumers to negotiate prices directly with producers and contract separately with the pipelines for transportation.

1987 FERC Order 500

Order 500 implemented shared contract costs on take-or-pay (TOP) contracts. Take-or-pay contracts leave the buyer responsible for some portion of the cost even if the product is not provided.

The combination of Orders 436 and 500 allowed producers to balance supplies of gas across production regions - if volume was lacking in one area, but plentiful in another, the producer could arrange to transport the surplus to where it was needed. The transportation system became a mechanism one party owned, but could be accessed by other parties on an equal basis - hence the concept of open-access. Differences between contract gas shipments and actual consumption left pipelines to make up the difference (balancing) and FERC made balancing a competitive service.

The establishment of gas market firms was also a feature of the 1980s, a direct result of deregulation. These firms, often with no ties to any one gas company, provided an intermediary service between a gas buyer and all other industry segments.

1989 Natural Gas Wellhead Decontrol Act

This act completed the process of deregulating wellhead prices. It required the removal of all price controls on wellhead sales as of Jan. 1, 1993, allowing natural gas prices to be freely set in the market.

1991 Mega-Notice of Proposed Rulemaking (Mega-NOPR)

FERC requested comments from consumers and industry about new ways of structuring gas transportation.

1992 The Restructuring Rule (FERC Order 636)

Order 636 resulted in major restructuring of interstate pipeline operations. The most notable provisions of Order 636 were the separation of sales from transportation services (unbundling), so that customers could select supply and transportation services from any competitor in any quantity and combination, making TOP contracts a thing of the past.

Order 636 successfully impacted the market resulting in increased exploration, pipeline construction, falling prices and increasing profits.

2000 FERC Order 637

Order 637 provided further refinement of the remaining pipeline regulations to address inefficiencies in the capacity release market.

Deregulation in the gas industry has seen the development of commodity products that parallel the evolution of physical natural gas markets. Consumers can negotiate the best terms for supply and transportation to their site and simultaneously negotiate better terms in other markets as a price hedge. The natural gas commodity market is now the most active commodity market on the NYMEX.

The deregulation of the US gas industry has been extremely successful - production has increased, proved reserves have decreased, gas usage is increasing and consumer prices have dropped significantly.

[Editor’s note: Circumstances have changed significantly since Platt’s wrote this conclusion.]

Source: http://www.platts.com/usgashistory.shtml